STATE OF MAINE
PUBLIC UTILITIES COMMISSION

May 17, 2002

EXAMINER'S REPORT

BANGOR HYDRO ELECTRIC COMPANY
Request for Approval of Alternative Rate Plan

Docket No. 2001-410

BANGOR HYDRO ELECTRIC COMPANY
Proposed Rate Change to Increase Annual Revenues Approximately $6.4 Million

Docket No. 2001-728

NOTE: This Report contains the recommendations of the Hearing Examiner and is in draft order format. A copy of this Report is being posted on the Commission's webpage. In order to broaden the opportunity for public participation in this matter, the Examiner waives the requirements of Section 760-A of the Commission's Rules of Practice and Procedure, and will allow non-parties to this case to file comments on the Examiner's Report. Such comments are due on **May 28, 2002** and should be filed with Dennis L. Keschl, Administrative Director, Public Utilities Commission, 242 State St., Augusta, Maine 04333. Exceptions and responses from the parties, including any responses to comments, may be filed by **May 31, 2002.** It is expected that the Commission will deliberate this matter at a specially scheduled deliberative session on **June 6, 2002.**

I. SUMMARY

By way of this Order, we approve a Stipulation entered into among Bangor Hydro-Electric Company (BHE), the Office of Public Advocate (OPA) and Georgia-Pacific Company (GP) and thus approve an Alternative Rate Plan (ARP) for BHE. The BHE ARP, as it is referred to in the Stipulation, will be in effect from the date of this Order through December 31, 2007. The Stipulation provides for annual rate changes to occur on July 1st of each year of the ARP commencing on July 1, 2003. The rate changes will occur in accordance with an Annual Percentage Price Change formula which is composed of Basic Rate Reductions, Mandated Costs, Net Capital Gains and Losses, Earnings Sharing and Service Quality Penalties. The first two Basic Rate

Reductions (BRR) to occur in 2003 and 2004 are set at –2.50% and –2.75%. The rate changes in years four (2005) through six (2007)of the ARP are dependent on inflation. If inflation in the two years prior to the time of those rates changes averages less than 3%, as is currently projected, the Basic Rate Reductions for those years will be –2.75%, -2.00% and –2.00%.

The ARP Stipulation also establishes service reliability and customer service performance levels and subjects BHE to penalties of up to $840,000 if BHE's performance drop below the established levels. In addition, as part of the Stipulation, the parties recommend dismissal of BHE current rate case proceeding including the management audit proposed in our January 10, 2002 Draft Order in that proceeding.

We find that the parties supporting the Stipulation represent a sufficiently broad spectrum of interests to ensure that there has not been disenfranchisement and that the process that led to the Stipulation was fair to all parties. In addition, we find that the results of the Stipulation are reasonable, in the public interest and consistent with legislative mandates.

II. BACKGROUND

In our Order approving the proposed merger between BHE and Emera, Inc. (Emera), BHE was directed to file an Alternative Rate Plan proposal within two months of the closing of the merger with Emera or by June 30, 2001, whichever was earlier. *Bangor Hydro-Electric Company; Maine Electric Power Company, Inc.; Chester SVC Partnership; and Emera, Inc., Request for Approval of Reorganization (Joint Petition),* Docket No. 2000-663, Order Rejecting Revised Stipulation and Approving Stipulation (Jan. 5, 2001). On June 15, 2001, BHE filed a letter with the Commission stating that it intended to file a comprehensive 4-year ARP covering both distribution service and standard offer service. BHE also requested that it be given an extension until July 31, 2001 to file its proposal to allow the Company sufficient time to develop a 4-year plan for standard offer service. In its letter, BHE also indicated that given the volatility in the power supply market, "the specific ARP pricing BHE plans to offer will likely only be available for a limited time" and therefore the Commission should act promptly on the Company's proposal.

A Notice of Proceeding granting BHE's request for extension and providing interested persons with an opportunity to intervene was issued on June 21, 2001. The Office of Public Advocate (OPA), the Industrial Energy Consumers Group (IECG), International Paper (IP), Georgia Pacific Corporation (GP), Independent Energy Producers of Maine (IEPM) and Competitive Energy Services (CES) filed petitions to intervene. Those petitions were granted in a Procedural Order dated July 18, 2001.[1]

On September 5, 2001, we issued our decision rejecting the Company's standard offer proposal. In that Order, we held that under the provisions of 35-A M.R.S.A. § 3212, before default standard offer service can be awarded to a transmission and distribution (T&D) utility, the Commission must first conduct a bid process and either not receive any bids or not receive any acceptable bids. Because the Commission was in the process of assessing bids from competitive service providers in response to the Commission's Request for Proposals (RFP) issued on July 19, 2001, we could not, at

[1]By way of a letter dated January 29, 2002, CES withdrew its petition to intervene in this proceeding.

that time, conclude that the bids we received were unacceptable. BHE filed a request for reconsideration of this decision which we denied on September 24, 2001.

In response to the Commission's denial of the Company's proposal to be designated as the standard offer provider as part of its "All-In ARP," on October 15, 2001, Bangor Hydro-Electric Company (BHE) filed a revised version of an Alternative Rate Plan (ARP). In this ARP proposal, BHE proposed to establish "starting point" distribution rates, based upon adjusted test year revenue requirements that were 6.11% higher than current distribution rates. BHE further proposed to adjust these rates annually by an inflation minus productivity offset formula and that the productivity offset be set at 1.0% during the ARP.[2] The OPA filed a motion to dismiss that portion of the Company's ARP which sought a starting point rate change as volatilive of the provisions of 35-A M.R.S.A. § 307 and Chapter 120 of the Commission's Rules.

On October 18, 2001, BHE filed a 2-month Notice of Intent to File a Rate Case under the provisions of 35-A M.R.S.A. § 307. In its Notice, the Company stated that it anticipated seeking an increase of approximately $6.4 million in annual distribution delivery revenues. This increase would represent approximately an 11.6% increase in the Company's distribution rates. The Company's rate case filing was assigned Docket No. 2001-728. A Notice of Proceeding was issued on December 14, 2001. Petitions to intervene were filed by the OPA, the IECG and Donna Robinson, a residential ratepayer of BHE.

[2]The Company's proposed price change formula also included provisions for the flow-through of mandated costs, earnings sharing and service quality incentives and penalties.

On January 10, 2002, the Commission issued a draft order proposing to initiate a management audit of BHE. In this proposed order, the Commission noted that, given the Company's current high rate structure, recent rate activity and potential for savings from the merger with Emera, Inc., it appeared appropriate to conduct a management audit to examine the Company's current cost structure, its operating efficiency, and the potential for savings from the merger. Comments on the draft order were filed by BHE, the OPA and the IECG.

In its comments, BHE argued against conducting such a management audit. First, BHE asserted that while its rates may be higher than those of Maine's other electric utilities, this alone did not justify a management audit. Second, the Company noted that the scope of the management audit would require the devotion of significant management resources. Finally, the Company expressed concern about being forced to enter into a contract with a management auditor selected by the Commission.

As an alternative to the initiation of the management audit, the Company offered to defer the filing of its rate case for a 90-day period. At the same time, the Commission would defer initiating its management audit. During this period, the Commission staff and parties to the Company's Alternative Rate Plan (ARP) case could attempt to negotiate a mutually acceptable ARP for BHE. The Company argued that if these discussions were successful there would be no need for either a management audit or a rate case. BHE further stated that to demonstrate its good faith, the Company was willing to use current rates as the starting point for the ARP, assuming the other provisions of the ARP were reasonable.

The comments of both the IECG and the OPA were filed after, and in response to, BHE's comments. The IECG stated that it considered BHE's proposal to be an intriguing alternative to the management audit and had the potential to provide greater ratepayers benefits than a rate case and management audit. Therefore, the IECG recommended that the Commission defer deliberations on the draft order and offer BHE the opportunity to more fully present the alternatives alluded to in its proposal. The IECG noted that it welcomed the opportunity to explore ratemaking alternatives for BHE.

The OPA recommended that the Commission reject the Company's proposal. First, the OPA noted that it was skeptical about the prospects for a successful ARP negotiation if the Company had a $6.4 million rate increase that it could activate if negotiations failed. Second, the OPA considered the results of the audit to be necessary in the design of an ARP for BHE. Finally, the OPA noted that it was doubtful that BHE would drop its $6.4 million rate increase request unless it were going to recover this money during the ARP and therefore, negotiations under such conditions appeared to be pointless.

By way of an Order dated February 28, 2002, we accepted BHE's proposal to defer the initiation of the management audit described in our draft order of January 10, 2002 for 90 days to allow intervenor stakeholders to discuss the development of a mutually acceptable ARP. We found at that time that the mutual deferral, or "cooling off" proposal offered by the Company, provided a no-lose situation for ratepayers in that BHE would not begin the formal process to increase its rates during the "cooling off" period and the Commission retained all of its options to initiate an audit if a mutually acceptable ARP was not developed. Regarding the OPA's concern about information that the audit would supply in designing an ARP, we encouraged the Company to provide information to stakeholders during the collaborative process to allow such parties to have a meaningful dialogue on ARP alternatives.

A case conference to discuss the procedure to be followed in both the rate case and the ARP case in light of the Commission decision to accept BHE's cooling off proposal was held on January 25, 2002. Based on the discussions at the conference the initial collaborative session was held on February 14, 2002. A number of collaborative sessions were duly scheduled and held subsequent to this initial collaborative process.[3]

On April 26, 2002, Bangor Hydro-Electric Company (BHE) and the Office of Public Advocate (OPA) filed a Stipulation in the above-referenced matter which, if adopted, would establish an Alternative Rate Plan (ARP) for BHE through December 31, 2007. The cover letter to the Stipulation stated that the other parties to the case had not yet indicated their final position on the Stipulation.

A conference of counsel to ascertain the other parties' position on the Stipulation and to discuss what procedure should be adopted as part of the Commission's consideration of the Stipulation was held on May 2, 2002. At such time Anthony Buxton, counsel for Georgia Pacific, International Paper (IP) and the Industrial Energy Consumers Group (IECG) indicated that Georgia Pacific would be joining the Stipulation. Mr. Buxton also stated that while IP and the IECG would not be joining the Stipulation, they did not oppose the Stipulation nor did they request a hearing. Eric

[3]During the collaborative process, BHE responded to approximately 27 oral data requests from the OPA and the Advisory Staff.

Bryant, counsel for the OPA, stated that he had talked with Donna Robinson, a ratepayer/intervenor, who also indicated that while she did not support the Stipulation, she did not intend to actively oppose the Stipulation and did not request a hearing. The Commission has also been informed that the IEPM, who has not been an active participant in these proceedings subsequent to the Commission's decision on BHE's "All-In" standard offer proposal, also does not object to the Stipulation. Given the lack of opposition to the Stipulation, all parties agreed that a hearing on the Stipulation was unnecessary.[4]

III. DESCRIPTION OF THE STIPULATION

A. Price Change Provisions

The Stipulation proposes a comprehensive Alternative Rate Plan for BHE (BHE ARP) which will apply to BHE's Maine distribution revenue requirement and rates.[5] The ARP is to take effect on the date of Commission approval of the Stipulation and is to run through December 31, 2007.

Beginning July 1, 2003 and on each July 1 during the remainder of the

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[4]The Stipulation provides that the record on which the Commission may base its determination on whether to accept and approve the Stipulation shall consist of BHE's request for ARP approval and all attachments thereto and any other material furnished by the Advisory Staff to the Commission, either orally or in writing, to assist the Commission in deciding whether to accept and approve the Stipulation. Stipulation at 35. For purposes of considering the Stipulation, BHE's responses to both the formal requests submitted in Docket No. 2001-410 and the responses to all informal requests as well as the Advisory Staff's May 3, 2002 response to the IECG's informal data request will be admitted into the record.

[5]BHE's stranded cost rates and revenue requirements as well as FERC jurisdictional transmission rates and revenue requirement are excluded from coverage of the BHE ARP.

Plan, distribution rates will change only in accordance with an Annual Percentage Price Change formula. The Annual Price Change formula is composed of the following elements: Basic Rate Reductions, Mandated Costs, Net Capital Gains and Losses, Earnings Sharing and Service Quality Penalties. The Basic Rate Reductions agreed to are set at –2.5% and –2.75% in 2003 and 2004 respectively. In 2005, 2006 and 2007, if the Inflation Index (I) is less than or equal to 3%, the BRR will be –2.75% in 2004, and –2.00% in 2006 and 2007. If the Inflation Index is greater than 3% in those years, the BRR reductions will be calculated by subtracting 5.75% from the Inflation Index in 2005 and by subtracting 5.00% from the Inflation Index in years 2006 and 2007. For purposes of calculating the Basic Rate Reductions, the Inflation Index will be based upon the average of the annual rates for the preceding two years using the Gross Domestic Product - Price Index (GDP-PI) chain type, as reported by the U.S. Department of Commerce, Bureau of Economic Analysis.

There are two types of mandated costs which are eligible for inclusion in the Annual Price Change Index. The first category of eligible mandated costs are *force majeure* non-recurring events. By way of example, the Stipulation lists extraordinary weather events, flood, riot, terrorism, sabotage, war, strike or labor, labor disturbance (other than by BHE's employees) or acts of God as Category One type events. Category Two type mandated costs can be recurring or non-recurring in nature and include ongoing costs that result from accounting, federal or state legislative, regulatory or tax changes. To be eligible for inclusion in the Annual Price Change, each individual mandated cost item must exceed $50,000. In the aggregate only those annual mandated costs which exceed $750,000 will be included in the Annual Price Change formula.

Capital gains and losses from the sale of operating property will be included in rates as part of the price change to the extent any individual capital gain exceeds $50,000. If in a year there is more than one eligible capital gain item, all such items shall be combined to determine a net capital gain and then netted against eligible mandated cost items. Any remaining net capital gain or loss in excess of $50,000 after such netting shall be flowed back to the ratepayers in the same manner as a non-recurring cost.

Finally, the Stipulation contains an earnings sharing mechanism which calls for adjustment to the rates if Return on Equity (ROE) on the Company's distribution investment for any calendar year falls below 5.0% or exceeds 17%. If the distribution ROE is below the 5.0% level, 50% of the deficiency will be included in the price change as a positive adjustment or increase to rates. If, on the other hand, the distribution ROE is above 17%, 50% of the excess will be flowed through as a negative adjustment or decrease to rates. Earnings sharing will not apply to earnings during 2002 and will begin to be calculated in calendar year 2003 for inclusion in the 2004 price change.

B. Service Reliability and Customer Service

Service Quality will be measured during the ARP through a Service Quality Index (SQI). The SQI is made up of the following seven indicators: Customer Average Interruption Duration Index (CAIDI); System Average Frequency Index (SAIFI), Percent of Business Calls Answered; Service Order Timeliness; MPUC Complaint Ratio; Bill Error Rate; and Market Responsiveness.

Baseline performance levels are established for each of the seven indicators. If the Company fails to meet the baseline performance levels, points will be deducted for each indicator for which the Company fails to meet the baseline. Each point deduction is worth $93,000 and will be calculated based on the percentage by which the indicator deviates from the baseline. The maximum penalty for any one year is $840,000.

In addition, as part of the ARP's service quality program, the Company has agreed to certain reporting requirements. Specifically, the Company is to file bi-monthly reports on all SQI indicators with appropriate supporting data. In addition, each year on March 15, the Company is to submit a review of SQI indicators for the preceding year and supporting data; an explanation of any substandard performance or analysis of service reliability for each BHE service area; an identification of the Company's "worst" performing circuits and a description of the improvements undertaken or planned for such circuits; and a description and update of BHE's power quality program. Finally, each July, beginning in 2003, BHE is to include as part of each customer's bill a "Customer Report Card" which provides a list of all SQI indicators, the baseline performance level for each and the Company's actual performance during the previous year. Service quality reporting requirements will take effect immediately. However, similar to the earnings sharing mechanism, the SQI penalty calculation will begin to be calculated in calendar year 2003 for inclusion in the 2004 price change.

In addition to the SQI measurement and penalty provisions set out above, the parties to the Stipulation have agreed to convene a statewide Power Quality Task Force made up of interested stakeholders, including the Commission Staff, Central Maine Power Company and Maine Public Service Company, to investigate alternatives for measuring power quality service performance and where appropriate provide recommendations to the Commission for a new power supply quality service performance indicator. Finally, the Stipulation provides for a mid-period service quality review to be commenced on or before July 1, 2004. At such time, the parties are to consider replacing the MPUC Complaint Ratio with an alternative that measures satisfaction with the Company's customer service and also to consider adding an appropriate power quality indicator.

IV. DECISION

A. Standard of Review

To accept a stipulation the Commission must find that:

1. the parties joining the stipulation represent a sufficiently broad spectrum of interests that the Commission can be sure that there is no appearance or reality of disenfranchisement;

2. the process that led to the stipulation was fair to all parties; and

3. the stipulated result is reasonable and is not contrary to legislative mandates.

See Central Maine Power Company, Proposed Increase in Rates, Docket No. 92-345(II), Detailed Opinion and Subsidiary Findings (Me. P.U.C. Jan. 10, 1995), and

Maine Public Service Company, Proposed Increase in Rates (Rate Design), Docket No. 95-052, Order (Me. P.U.C. June 26, 1996). We have also recognized that we have an obligation to ensure that the overall stipulated result is in the public interest. *See Northern Utilities, Inc., Proposed Environmental Response Cost Recovery,* Docket No. 96-678, Order Approving Stipulation (Me. P.U.C. April 28, 1997).

We find that the proposed Stipulation in this case meets all these criteria. For the reasons described below, we conclude that the BHE ARP agreed to in the Stipulation obviates the need for the audit contemplated by our January 10, 2002 draft order and thus find the Stipulation's provision that we not pursue such an audit as part of the dismissal of Docket No. 2001-728 to be acceptable.

B. Parties to the Stipulation and the Process

The Stipulation before us was entered between the Company and the OPA and Georgia Pacific. In past cases, we have found that the utility and the OPA, which generally represent opposite views in the ratemaking process, constitute a sufficiently broad spectrum of interests to satisfy the first criteria. *See Public Utilities Commission, Investigation of Stranded Cost Recovery, Transmission and Distribution Utility Revenue Requirements and Rate Design of Bangor Hydro-Electric Company (Phase II),* Docket No. 97-596, Order at 6 (Feb. 29, 2000) and *Maine Public Utilities Commission, Investigation of Retail Electric Transmission Services and Jurisdictional Issues,* Docket No. 99-185, Order Approving Stipulation (Maine Public Service Company) at 3 (Aug. 11, 2000). We thus find that the Stipulation here, entered into between the utility, the OPA and a major industrial group, satisfies criterion one.

We also find that the second criterion has been met in this case. There has been no suggestion that the process that lead up to the Stipulation was anything but fair. Our review of the record in this case indicates that although the process that led up to the Stipulation was informal, the Company was fully compliant in responding to requests for information and that all procedural safeguards were satisfied in this instance.

Although no party in this matter opposes the Stipulation or objects to any of the Stipulation's provisions, we must still satisfy ourselves that the stipulated result is reasonable and in the public interest and that the Stipulation's provisions are consistent with statutory requirements. We address these issues below.

C. Fairness and Reasonableness of the Stipulated Result and Consistency with the Public Interest

In deciding whether the Stipulation is reasonable, fair and consistent with the public interest, the entire Stipulation must be considered as a package. Whether we disagree with a particular stipulation provision or would have come up with a different result were we to decide the case after litigation is not the question. The question is whether the particular proposal as a package before us is reasonable and consistent with the public interest. *See* Docket No. 92-345 (Phase II), *supra.,* Order at 3. In deciding this question, detriments which have been raised by the parties, or which we identify, must be weighed against the benefits of the Stipulation. For the reasons set forth below, we find that the stipulated result, when looked at as whole, is fair, reasonable and in the public interest and that the benefits of the Stipulation clearly outweigh any possible detriments which we can identify.

The first benefit we see the Stipulation conferring upon ratepayers is the withdrawal of the Company's rate increase request. In its rate case notice, the Company estimated its increase request would be $6.4 million. As part of the collaborative process, the Commission's Advisory Staff and the Office of Public Advocate requested the Company to provide the necessary financial data which supported the increase request. While it is not possible to predict with any certainty what the result of a fully litigated rate case would have been, based upon our review of the information, it appears that a significant portion of the Company's request seems to have been justified, at least on a strict historic test year basis.[6] Thus, we find that the benefit conferred upon ratepayers by the Company's withdrawal of its request to increase distribution rates by $6.4 million, or 11.6%, to be real and substantial.

The second major benefit we see as being conferred upon ratepayers by the Stipulation is the substantial rate reductions that should occur during the course of the ARP as a result of the agreed-to Basic Rate Reductions. While the actual rate changes may vary due to mandated costs, earnings sharing or service quality penalties, under current inflation forecasts the Basic Rate Reductions during the course of the ARP will serve to reduce distribution delivery rates during the course of the ARP by 11.4% in nominal dollar terms.[7] After incorporating the impact of inflation, and recognizing this year's freeze in rates incorporated into the Stipulation, the reductions in real dollar terms will be approximately 25%. In terms of dollar savings to customers,

[6]We address the issue of the possible adjustments to the historic test year case which could result from a management audit below.

[7]As used in this Report, the term "current inflation forecast" refers to the Blue Chip Index Consensus Forecast.

these Basic Rate Reductions will save customers in the neighborhood of $21 million during the course of the ARP relative to current rates.

If we look at the Basic Rate Reductions in terms of the more classic "inflation minus productivity" incentive ratemaking formula, based on current inflation forecasts, the productivity offsets implied by the Basic Rate Reductions on average are approximately 4.5%. In *Central Maine Power Company, Request for Approval of Alternative Rate Plan (Post-Merger) "ARP 2000,"* Docket No. 99-666, Order Approving Stipulation at 14, we approved an ARP which for CMP contained an average productivity offset of 2.53%. In CMP's first ARP approved by the Commission in 1995, the productivity offset was 1.0% while the Rate Plan we adopted for Bangor Hydro-Electric Company in 1999 we set the productivity offset at 1.2%. *Bangor Hydro-Electric Company, Proposed Increase in Rates,* Docket No. 97-116, Order at 63. The productivity offsets implied in the BHE ARP greatly exceed any level we have approved in the past for an electric utility and again provide BHE's ratepayers with a tangible and substantial benefit.

We also find that BHE's ratepayers will benefit from the service quality and reliability criteria agreed to in the BHE ARP. Under the ARP's SQI mechanism, BHE will face automatic penalties of up to $840,000 should their service not meet the established standards. The service quality indicators agreed to will measure the Company's service reliability performance (CAIDI and SAIFI), customer service (percentage of business calls and outage calls answered within 30 seconds; service order timeliness; PUC complaint ratio; and Bill Error Rate) and market responsiveness (CEP enrollments processed in compliance with Chapter 322).

We find that these indicators provide a broad range of performance measures to ensure that service quality during the ARP is appropriately measured and that the performance levels agreed to for each of the indicators as well as the penalty levels are reasonable.[8] Consistent with past ARP service quality indices, the measurements here are based primarily on BHE's past service performance and are designed to ensure that BHE's service during the ARP will not be sacrificed in order to meet Company earnings' goals during the ARP.[9] In addition, the penalty level of $840,000 which represents approximately 1.5% of distribution delivery revenue requirement and is comparable in scale to CMP's ARP maximum penalty level, should provide adequate incentive to maintain adequate and reliable service.

Before deciding that the stipulated result is fair, reasonable and in the public interest, any detriments we identify must be weighed against the benefits discussed above. The parties to the Stipulation have agreed that the Company's rate case including the management audit proposed in our January 10, 2002 draft order be dismissed. We thus must consider whether this provision, in the context of our

[8]We are somewhat disappointed that the parties were unable to reach agreement on an indicator to measure power quality. However, we recognize that the area of power quality measurement is in its early stages. We are encouraged by the Stipulation's provision to commence a statewide Power Quality Task Force in the upcoming months to address the power quality measurement issue and by the parties' commitment to consider an appropriate power quality indicator as part of the SQI mid-period review.

[9]We note that in comparing the reliability levels agreed to here with CMP's ARP 2000 standards, BHE's expected reliability performance level is higher. Specifically, the outage duration measurement (CAIDI) for BHE is 2.13 while the same measurement criteria for CMP is 2.58. The outage frequency index (SAIFI) is 1.43 for BHE and 1.80 for CMP.

evaluation of the fairness and reasonableness of the Stipulation, constitutes a detriment and, if so, whether this detriment outweighs the benefits identified above.

Subsequent to the time of our decision approving the "cooling off" period and setting up the collaborative process which led to the Stipulation, we have received a number of letters from BHE's ratepayers urging us not to forego, or even to delay any further, the contemplated audit. Based on our review of these letters there seems to be a belief, at least on behalf of some BHE's ratepayers, that the audit contemplated by our January 10th Order was a financial or accounting audit and that by delaying or not pursuing the audit, BHE could "cook its books" and defeat the purposes of an audit. Although our draft order expresses some serious concerns about BHE's management efficiency at the time of its issuance, we never suspected, nor had reason to believe, either at the time we issued our January 10th draft order or at any time since, that BHE was misreporting financial information to this or any other regulatory body or in any way concealing financial information from us. Accurate and honest financial reporting from the public utilities we regulate is essential for this Commission to perform effectively and is an absolute and non-waivable requirement. If we had any reason to believe that BHE had somehow fallen short of its reporting duty, no amount of rate decreases agreed to in a stipulation would warrant or could persuade us not to do a full financial audit of the Company. However, based on our review of the information in this proceeding, there is no reason to suspect that BHE is misreporting its financial data.

What was contemplated in our January 10th draft order was an audit of BHE's operations, management practices, management structure and staffing to determine if BHE was operating as efficiently as possible. The impetus for the audit was the fact that BHE's distribution rates were relatively high compared to the other Maine utilities with no obvious reason why such a differential should exist. As noted in the draft order, our consideration of a management audit was not intended to be a punitive response to the Company's notice of rate case filing. It was indicative of our concern about BHE's already high rates, which BHE was proposing to increase further, and our view that the combined Emera/BHE entity should be able to realize cost savings that would ultimately result in rate reductions to BHE's customers. The management audit then was an expression to the Company of our belief that business as usual was no longer acceptable and that every cost increase experienced by the Company could not be passed onto the Company's ratepayers. It is very obvious to us, given the substantial rate decreases agreed to in the Stipulation, that Emera and BHE's new management team now understands our concerns and has responded appropriately.

As a full participant in the collaborative process that resulted in the Stipulation, the Advisory Staff has analyzed the likely financial results of the ARP ultimately agreed to by modeling BHE's future expenses, revenues and return on equity. The modeling was done to help assure the parties to the process and ultimately the Commission that the ARP was fair to both ratepayers and shareholders. This modeling demonstrates that with the agreed to reductions, the Company will have an opportunity to earn its return on equity approved in Docket No. 97-596 during the course of the plan. In order to achieve this level of earnings, however, the Company will need to achieve savings in O&M costs of 20% during the first 2 years of the plan, will need to keep O&M

constant during the remainder of the plan despite inflationary pressures, and will need annual average sales growth of approximately 2.5%.

We have no doubt that achieving the level of savings assumed in the Staff's modeling will require a tremendous amount of effort and will essentially require a reshaping of the Company. We do not, as part of this Order, attempt to dictate how this reshaping should occur. It will be up to the Company to determine how savings should be accomplished consistent with the Company's obligations to provide safe, adequate and reliable service. We understand that this process has already begun. The Company that exists today then is substantially different than the Company that existed at the time we issued our January 10th draft order and in all probability will not be the same Company that is in existence two years from now.

Management audits such as the one suggested by our January 10th draft order are often contentious, time-consuming for both the regulatory body and the utility, and represent a fairly large expense for the Company's ratepayers.[10] Where circumstances warrant, we would not, and have not, hesitated from the commitment of these resources.[11] Given the Company's commitment to withdraw its rate request, significantly reduce rates during the ARP, and the dynamic organizational changes

[10]Under the provisions of 35-A M.R.S.A. § 113, the full cost of a management audit are to be recovered from the subject utility's ratepayers.

[11]For example, based upon information collected by our Consumer Assistance Division, we recently initiated an audit of Northern Utilities (NU) to investigate NU's customer service practices including call center responsiveness, billing accuracy and response to large scale outages. *Public Utilities Commission, Management Audit of Northern Utilities, Inc.'s Customer Service and Investigation to Implement Service Quality Incentive Plan,* Docket No. 2002-140, Order Initiating A Management Audit and Investigation of Service Quality Incentive Plan (May 16, 2002).

occurring at the Company, we find that a management audit at this point in time would not provide the Commission with any useful information and would constitute an unreasonable cost for the Company's ratepayers.

In many ways the circumstances surrounding this case are quite similar to the situation the Commission faced in the early 1990s involving CMP. In August of 1992, the Commission initiated a management audit of CMP following increases in rates of 26.6% since January 1990. *Central Maine Power Company, Proposed Increase in Rates and Rate Design,* Docket No. 89-068, *Public Utilities Commission, Investigation into Central Maine Power Company's Ratepayer Complaints,* Order at 67 (Aug. 5, 1992). The Commission announced in that decision that it would include the results of this management audit in CMP's next base case. On March 1, 1993, CMP filed a request for an additional $83.1 million, or approximately a 9.8% rate increase.

Following one of the most contentious proceedings in recent Commission history, CMP's revenue requirement increase was reduced to $26.2 million. This reduction included a reduction of $25.3 million for efficiency savings which was based on the management audit finding of $15.2 million to $32.0 in potential efficiency savings. *Central Maine Power Company, Proposed Increase in Rates,* Docket No. 92-345, Order at 123 (Dec. 14, 1993). As part of its decision in that case, the Commission concluded that it should consider moving from traditional cost of service/rate of return regulation to a multi-year price cap approach. *Central Maine Power Company, Proposed Increase in Rates,* Docket No. 92-345, Order at 125 (Dec. 14, 1993). The Commission found that a multi-year cap plan would provide the following benefits: (1) electricity prices continue to be regulated in a comprehensive and predictable way; (2) rate predictability and stability are more likely; (3) regulatory "administration" costs can be reduced, thereby allowing for the conduct of other important regulatory activities operations; (4) risks can be shifted to shareholders and away from ratepayers (in a way that is manageable from the utility's financial perspective; and (5) because exceptional cost management can lead to enhanced profitability for shareholders, stronger incentives for cost minimization are created. *Id.* at 130. The Commission therefore initiated a follow-up proceeding to develop a price cap plan for CMP.

After nearly a year of litigation, the Commission approved a Stipulation which established a 5-year Alternative Rate Plan (ARP 95) for CMP. *Central Maine Power Company, Proposed Increase in Rates,* Docket No. 92-345 (Phase II), Detailed Opinion and Subsidiary Findings (Jan. 10, 1995). ARP 95 allowed CMP's rates to change based on changes to the rate of inflation, measured by the GDP-PI, less a productivity offset of approximately 1.00% and further adjusted for mandated costs, earnings sharing and service quality penalties.

We find that the parties to the Stipulation in this case have been able to accomplish in a relatively short period of time and, through a collaborative process, what took many years of litigation to accomplish in CMP's management audit/ARP process back in the 1990s. In fact, from a ratepayer perspective, the results achieved here are far superior to those achieved in the CMP audit/ARP litigation. First, the parties here totally eliminated the base rate increase which spurred the management audit proposed. As noted above, CMP still received a 3% increase in rates in Docket No. 92-345, despite a very aggressive management efficiency adjustment. Second, the parties were able to develop a mutually acceptable ARP which produced rate reductions during the ARP in the area of 11.4% and produced all of the risk shifting benefits identified above by the Commission in Docket No. 92-345. Thus, we conclude that if a management audit were undertaken in lieu of the Stipulation, it is unlikely that the outcome would be as favorable to BHE's ratepayers as the Stipulation.

Our decision not to pursue an audit at this time should not be seen as a decision to exempt BHE from an audit in the future should circumstances warrant. As we have clearly stated in the past, our approval of an Alternative Rate Plan does not mean that the subject utility is put on an auto-pilot for the term of the ARP. We restate here what he have said on the prior occasions that no one should interpret our approval of the ARP Stipulation as a willingness to abandon our central regulatory task of ensuring that BHE's customers receive adequate service at just and reasonable rates.

D. Consistency with Legislative Mandates

35-A M.R.S.A. § 3195 authorizes the Commission to establish rate adjustment mechanisms, such as the ARP proposed by the Stipulation, which promote transmission and distribution utility efficiency. In determining the reasonableness of any such rate adjustment mechanism shall apply the standards of 35-A M.R.S.A. § 301.

As discussed previously, the proposed BHE ARP will provide the Company with an opportunity to earn a reasonable return on its investment. The ARP includes significant rate reductions which will ensure that BHE's ratepayers receive a fair portion of any efficiency savings achieved by the Company during the ARP. In addition, should BHE's returns exceed upper-end of the dead band (17%), ratepayers will receive 50% of the "excess" earnings. In calculating earnings for purposes of this sharing mechanism, neither the amortization, nor rate base portion, of Emera's acquisition premium will be included.

Taken together we find that these provisions, as well as the provisions in the Stipulation concerning mandated costs, capital gains and losses, as well as ARP's provisions on service quality satisfy us that the Stipulation is consistent with all legislative mandates.

Having found that the Stipulation satisfies all of the Commission's criteria for approval, we conclude that the Stipulation submitted to us on April 26, 2002 by the Company, the OPA and Georgia Pacific should be approved.

Dated: May 17, 2002

Submitted by,

Charles Cohen
Hearing Examiner

On Behalf of the Advisory Staff:

James Buckley
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